BEFORE THE
PUBLIC SERVICE COMMISSION
OF SOUTH CAROLINA
UTILITIES COMMISSION

DOCKET NO. 2014-246-E

In Re: Petition to Establish	**)**	
Generic Proceeding Pursuant to the	**)**	
Distributed Energy Resource	**)**	**DIRECT TESTIMONY OF R.**
Program Act,	**)**	**THOMAS BEACH ON BEHALF**
Act No. 236 of 2014,	**)**	**OF THE ALLIANCE FOR**
Ratification No. 241,	**)**	**SOLAR CHOICE**
Senate Bill No. 1189	**)**	

December 11, 2014

Table of Contents

Exhibit RTB-1

I. Introduction

A. Qualifications

Q: Please state for the record your name, position, and business address.

A: My name is R. Thomas Beach. I am principal consultant of the consulting firm Crossborder Energy. My business address is 2560 Ninth Street, Suite 213A, Berkeley, California 94710.

Q: Please describe your experience and qualifications.

A: My experience and qualifications are described in my *curriculum vitae* (attached as **Exhibit RTB-1)**. As reflected in my CV, I have more than 30 years of experience in the natural gas and electricity industries. I began my career in 1981 on the staff at the California Public Utilities Commission ("CPUC"), working on the implementation of the Public Utilities Regulatory Policies Act of 1978 ("PURPA"). Since 1989, I have had a private consulting practice on energy issues and have appeared or testified on numerous occasions before state regulatory commissions in Arizona, California, Colorado, Idaho, Minnesota, Nevada, New Mexico, North Carolina, Oklahoma, Oregon, and Virginia. My CV includes a list of the formal testimony that I have sponsored in various state regulatory proceedings concerning electric and gas utilities.

Q. Please describe more specifically your experience on benefit-cost issues concerning distributed generation.

A. In addition to working on the initial implementation of PURPA while on the staff at the CPUC, in private practice I have represented the full range of qualifying facility ("QF") technologies – both renewable small power producers as well as gas-fired cogeneration QFs – on avoided cost pricing issues before the utilities commissions in California, Oregon, and Nevada. With respect to benefit-cost issues concerning renewable distributed generation ("DG"), also known as distributed energy resources ("DER"), I have sponsored testimony on net energy metering ("NEM") and solar economics in California, Colorado, Idaho, Minnesota, New Mexico, North Carolina, and Virginia. In the last two years, I have co-authored benefit-cost studies of NEM or distributed solar generation in Arizona, Colorado, North Carolina, and California. I also co-authored a chapter on Distributed Generation Policy in *America's Power Plan*, a report on emerging energy issues, which was released in 2013 and is designed to provide policymakers with tools to address key questions concerning distributed generation resources.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of The Alliance for Solar Choice ("TASC").

B. Summary of Testimony

Q: Please summarize your testimony.

A: The purpose of my testimony is to propose an approach to developing a benefit-cost methodology for valuing distributed generation resources in South Carolina, consistent with the requirements of Act 236 and informed by the emerging best practices in valuing these resources. My testimony provides a brief overview of Act 236, and its provisions relating to distributed energy resources and net energy metering, including the role of the methodology that the Commission will approve to assess the benefits and costs of net metered DER systems in South Carolina.

There is a developing consensus in the utility industry on the best practices for designing benefit-cost analyses of net metering and distributed resources, a consensus which draws upon the similar analyses which have become standard practice for other types of demand-side resources. These analyses assess the benefits and costs of these resources from multiple perspectives, including the three perspectives that Act 236 has required to be used to analyze net metered DER. These perspectives include those of the principal stakeholders in DER development: (1) participating customer-generators, (2) other ratepayers, and (3) the utility system as a whole. I discuss recent benefit-cost studies of net-metered solar resources in Nevada and Mississippi which have examined the benefits and costs from these multiple perspectives. The goal of the regulator should be to balance the interests of all of these stakeholders. I recommend that the methodology adopted in South Carolina should build upon this experience, recognizing of course that South Carolina should tailor the details of the calculations to the specific loads, resources, and costs of its utilities.

This testimony also presents a close analysis of the net metering transaction, for several reasons. First, it illuminates how DER differs from other demand-side resources. DER customers are not just consumers of power, but also at times produce power for export to the utility system. Second, I discuss why the essence of net metering is valuing the power which customers with DER will export to the grid. Third, I dispel several common myths about net metering, including the misplaced ideas that NEM customers use the grid more than regular utility customers and that the grid serves to "store" their electric output for future consumption. Consistent with the analysis of South Carolina's net metering law in the testimony of TASC Witness James M. Van Nostrand, I suggest that the appropriate framework for assessing the relative benefits and costs of net metering is to focus on the value that customer receives for the electricity that is exported from their residence or premises.

The Commission should adopt a benefit-cost methodology for NEM and DER that has four key attributes:

1. Examine the benefits and costs from the multiple perspectives of the key stakeholders.
2. Use a long-term, life-cycle analysis.
3. Focus on NEM exports.
4. Consider a comprehensive list of benefits and costs.

The testimony briefly reviews the specific benefits and costs that should be examined and quantified. All of these benefits and costs have been quantified in other similar studies, and well-accepted techniques are available for this task. If there is uncertainty about the magnitude of a specific benefit or cost, the default should not be to assign a zero value to that benefit or cost, but to examine several cases that span a range of reasonable values. I illustrate this important point with a discussion of the benefit of reducing carbon emissions.

Finally, the testimony discusses how the results of the adopted methodology can be used to make rate design changes that impact the balance of the interests of the affected stakeholders, including customer-generators, other ratepayers who are not installing DER, and the utility. The types of changes that the Commission should prioritize are those that align rates more closely with utility costs, such as volumetric time-of-use rates, or that continue to allow the greatest scope for customers to exercise the choice to adopt DER, such as a minimum bill. Fixed charges or rate design changes that apply only to DER customers should be avoided, due to problems with customer acceptance, undue discrimination, and the future potential for customer bypass of the utility system. TASC Witness Justin Barnes provides further illustration of how other jurisdictions have approached this question through the regulatory process.

II. Background

Q. Why is the Commission considering proposals for a cost-benefit methodology from intervenors through this proceeding?

A. As noted in the *Petition to Establish Generic Proceeding Pursuant to the Distributed Energy Resource Program Act* ("ORS Petition"), filed by the Office of Regulatory Staff on June 5, 2014, the purpose of this generic proceeding is to "implemen[t] the requirements of Chapter 40, Net Metering, with respect to the net energy metering rates, tariffs, charges and credits of electrical utilities, and specifically to establish the methodology to set any necessary charges and credits as required under items (F)(1) and (2)."[1] Item (F)(4) specifically allows parties to submit methodologies that address Item F(2), which involves the application of the methodology to any new net metering rates, credits, or charges. I believe it was appropriate for the Legislature to encourage intervenor participation, as my experience in similar processes in other jurisdictions counsels that participation from multiple stakeholder perspectives is important to provide the Commission with a broad

[1] ORS Petition, at p. 3.

picture of the implications of the methodology and a fully-developed record to support any decision.

Q. Is it appropriate to consider broader considerations, such as rate design and the structure of the net metering tariff, as a part of this generic proceeding?

A. Yes, the statute describes the methodology in a broad context, including a consideration of how it will be applied.[2] In many respects, the proper application of the methodology is inseparable from issues of designing what benefit and cost categories should be included and how the methodology will capture those costs. For example, it is difficult to know what the "costs" of net metering are if there is any doubt about the nature of the net metering crediting mechanism. As TASC Witnesses Barnes and Van Nostrand discuss, the traditional net metering mechanism—measuring the difference over a billing period between the electricity which the customer supplies to the grid and the electricity which the customer takes from the grid—is a fundamental assumption in designing a cost-benefit methodology for the net metering program. Based on the testimony of Witnesses Van Nostrand and Barnes, my testimony assumes that any methodology should address the relative costs and benefits of true retail net metering, as that term is explained in Witness Barnes' testimony.

[2] The statute provides that "any charges or credits prescribed in item (1), and the terms and conditions under which they may be assessed shall be in accordance with a methodology established through the proceeding in item (4)."[2] Intervenors have the right under item (F)(4) to present a methodology that will be used to establish any new rates, charges or credits.

III. Proposal for Developing a Benefit-Cost Methodology

A. National Context: Toward a Consistent Approach

Q: Section 58-40-20(F)(2) requires that the benefits and costs of net metering in South Carolina should be allocated and recovered in rates based on "an analysis and calculation of the relative benefits and costs of customer generation to the electrical utility, the customer-generators, and those customers of the electrical utility that are not customer-generators." Is there a developing consensus on the best practices for designing benefit-cost analyses of NEM and DG resources, including solar photovoltaic ("PV") systems, installed behind the customer's meter, that should inform how the Commission undertakes this analysis?

A: Yes, there is. In this regard, the first and perhaps most important observation is that the issues raised by the growth of demand-side DG are not new. The same issues of impacts on the utilities, on non-participating ratepayers, and on society as a whole arose when state regulators and utilities began to manage demand growth through energy efficiency ("EE") and demand response ("DR") programs. To provide a framework to analyze these issues in a comprehensive fashion, the utility industry developed a set of standard cost-effectiveness tests for demand-side programs.[3] These tests examine the cost-effectiveness of demand-side programs from a variety of perspectives, including from the viewpoints of the program participant, other ratepayers, the utility, and society as a whole.

[3] See the *California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects* (October 2001), available at http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF.

This framework for evaluating demand-side resources is widely accepted, and state regulators have years of experience overseeing this type of cost-effectiveness analysis, with each state customizing how each test is applied and the weight which policymakers place on the various test results. This suite of cost-effectiveness tests is now being adapted to analyses of NEM and demand-side DG/DER more broadly, as state commissions recognize that evaluating the costs and benefits of all demand-side resources – EE, DR, and DG – using the same cost-effectiveness framework will help to ensure that all of these resource options are evaluated in a fair and consistent manner.

Each of the principal demand-side cost-effectiveness tests uses a set of costs and benefits appropriate to the perspective under consideration. These are summarized in **Table 1** below. "+" denotes a benefit; "-" a cost.

Table 1: *Demand-side Cost/Benefit Tests*

Perspective (Test)	DG Customer (Participant)	Other Ratepayers (RIM)	Resource Cost to Utility or Society (TRC)
Capital and O&M Costs of the DG Resource	–		–
Customer Bill Savings or Utility Lost Revenues	+	–	
Benefits (Avoided Costs) -- Energy -- Generating Capacity -- T&D, including losses -- Reliability/Resiliency/Risk -- Environmental / RPS		+	+
Federal Tax Benefits	+		+
Program Administration & Integration Costs		–	–

The key goal for regulators is to implement demand-side programs that produce balanced, reasonable results when the programs are tested from each of these perspectives. A program will need to pass the Participant test if it is to attract customers by offering them an economic benefit for their participation – thus, their bill savings and tax benefits should be comparable to the cost of participating. The program also should be a net benefit as a resource to the utility system or society more broadly – thus, the total resource cost (TRC) test compares the costs of the program to its benefits, which are principally the costs which the utility can avoid from the reduction in demand. The ratepayer impact measure (RIM) test gauges the impact on other, non-participating ratepayers: if the utility's lost revenues and program costs are greater than its avoided cost benefits, then rates may rise for non-participating ratepayers in order to recover those costs. This can present an issue of equity among ratepayers. The RIM test sometimes is called the "no regrets" test because, if a program passes the RIM test, then all parties will benefit from the program. However, it is a test that measures equity among ratepayers, not whether the program provides an overall net benefit as a resource (which is measured by the TRC test).

Q: Do these standard tests adequately provide "an analysis and calculation of the relative benefits and costs of customer generation to the electrical utility, the customer-generators, and those customers of the electrical utility that are not customer-generators," as set forth in Section 58-40-20(F)(2)?

A: Yes, they do.

B. Experience in Other States: Nevada and Mississippi

Q: Can you provide examples of other state commissions which have developed analyses of NEM from the three perspectives which you have described?

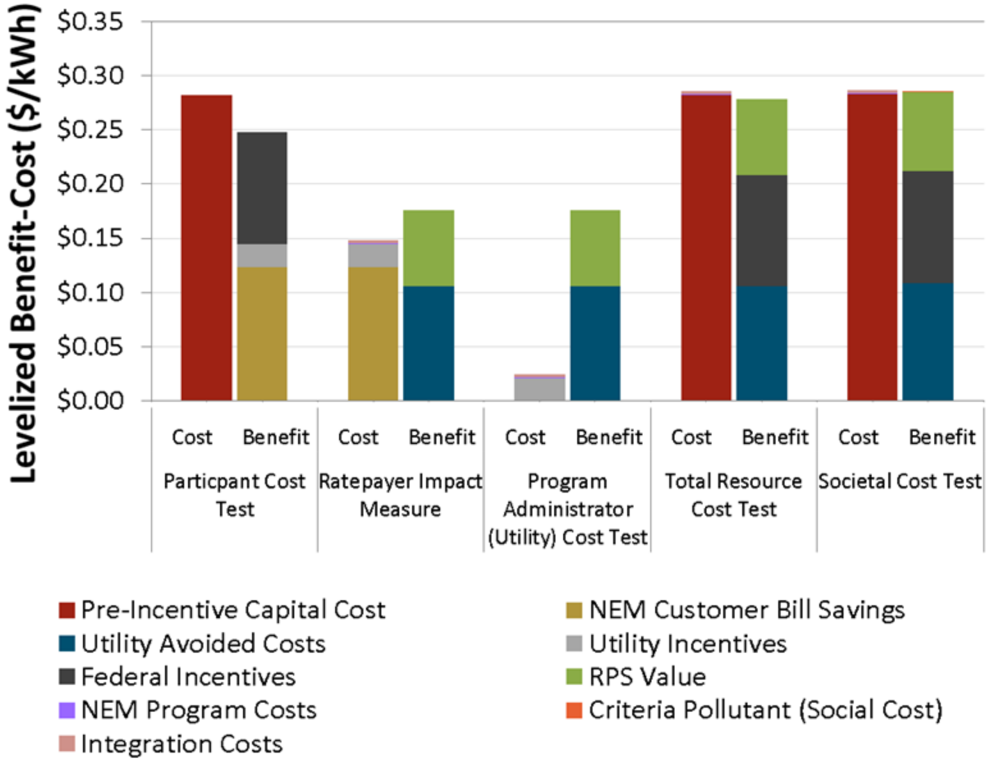
A: Yes. The Public Utilities Commission of Nevada ("PUCN") adopted this multi-perspective approach in the net metering study which it released on July 1, 2014.[4] The consulting firm Energy and Environmental Economics (E3) performed the analytic work for this study, and I served on a Stakeholder Committee that the PUCN convened to provide input on the study methodology and analysis. **Figure 1** below shows the costs and benefits of net-metering for solar PV systems in Nevada going forward, in the years 2014-2016, from each of the key stakeholders' perspectives.[5]

---

[4] The PUCN's net metering study, including the spreadsheet models used in the study, can be found at: http://puc.nv.gov/About/Media_Outreach/Announcements/Announcements/7/2014_-_Net_Metering_Study/ .

[5] This figure is from the "Results" tab of the "Nevada Public Tool" model, with the model set to produce results for solar PV and for the going-forward period of 2014-2016.

Figure 1: *Public Utilities Commission of Nevada NEM Study Results*



Notably, the Nevada study shows that NEM is cost-effective for non-participating ratepayers (*i.e.*, the benefits in the RIM test exceed the costs), while the costs are somewhat higher than the benefits for participants (*i.e.*, for solar customers). As with any such set of cost-effectiveness tests, it is not reasonable or practical to expect each of these tests to achieve a precise 1.0 benefit/cost ratio. Instead, the goal should be to achieve a reasonable, equitable balance of benefits and costs for all concerned – solar customers, other ratepayers, and the utility system as a whole. In my judgment, the Nevada study shows that NEM at the full retail rate, without any further rate design modifications, achieves that desired “rough justice” balance of interests in Nevada today.

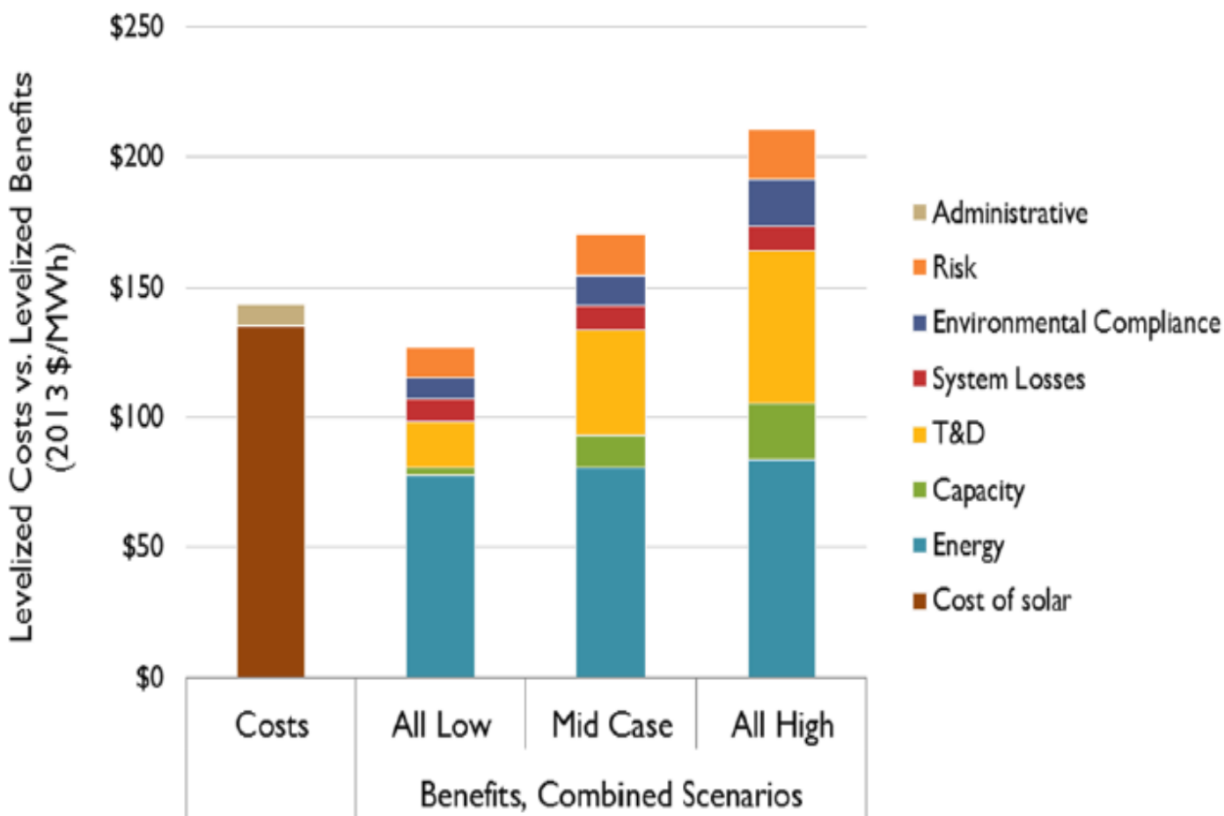
Q: Do you have any other recent examples?

A: Yes. The Public Service Commission of Mississippi also recently completed a NEM benefit/cost analysis.[6] As in South Carolina, a new NEM program is being implemented in Mississippi. As in the Nevada NEM study, the Mississippi study considered the three principal perspectives discussed above, with a focus on the TRC test because that test best captures the benefits and cost for the state as a whole from this new resource. The following figure summarizes the mid-case costs and benefits from Mississippi's TRC analysis, plus the maximum low and high sensitivity cases for the benefits.

---

[6] Elizabeth A. Stanton, et al., *Net Metering in Mississippi: Costs, Benefits, and Policy Considerations* (Synapse Energy Economics for the Public Service Commission of Mississippi, released September 19, 2014); hereafter "Mississippi Study." Available at http://www.synapse-energy.com/sites/default/files/Net%20Metering%20in%20Mississippi.pdf .

Figure 2: *Public Service Commission of Mississippi NEM Study Results*



As a result of this analysis, the Mississippi study concludes that net metered solar projects will provide a net benefit to Mississippi in almost all of the cases considered. However, the study's analysis of the Participant cost test expressed concern that NEM bill savings at the retail rate will not provide adequate benefits to drive significant adoption of solar DG in the state. As a result, the study suggests that solar customers should be compensated at a rate <u>higher</u> than retail rates. This higher rate would be based on the utilities' avoided costs, so that it would not shift costs to non-participants.[7] Finally, the Mississippi Study criticizes the use of the traditional RIM test, particularly in the context of a new NEM program. The problem with the RIM test is that the cost shift measured by the RIM test is simply a re-allocation of costs which the utilities have already incurred and which are not incremental costs resulting from the NEM program. Due to this limitation, the RIM test should not be used to judge the merits of the new NEM program. The study suggests an alternative measure, the ratio of long-term revenue requirement savings to lost revenues. This ratio is greater than 1.0 in Mississippi, indicating that NEM will tend to reduce rates in the long-run.[8]

C. The DG Customer as "Prosumer"

Q: The framework you have proposed and illustrated with examples from the Nevada and Mississippi commissions draws on benefit-cost analyses used for other types of demand-side programs. But isn't there a crucial difference between DG/DER and other demand-side resources: DG is generation that at times can supply power to the grid, whereas EE and DR only reduce the demand for power?

A: This difference exists, is important, and should be considered. DG located behind the meter will both reduce the demand for power from the utility, and, at times, will supply power to the utility. When a DG system produces more power than the on-site load requires, the excess is exported to the grid, and the DG owner is no longer a consumer, but becomes a supplier (i.e. a generator). Some have applied a new label – "prosumers" – to DG customers in

---

[7] Mississippi Study, at 49-50.

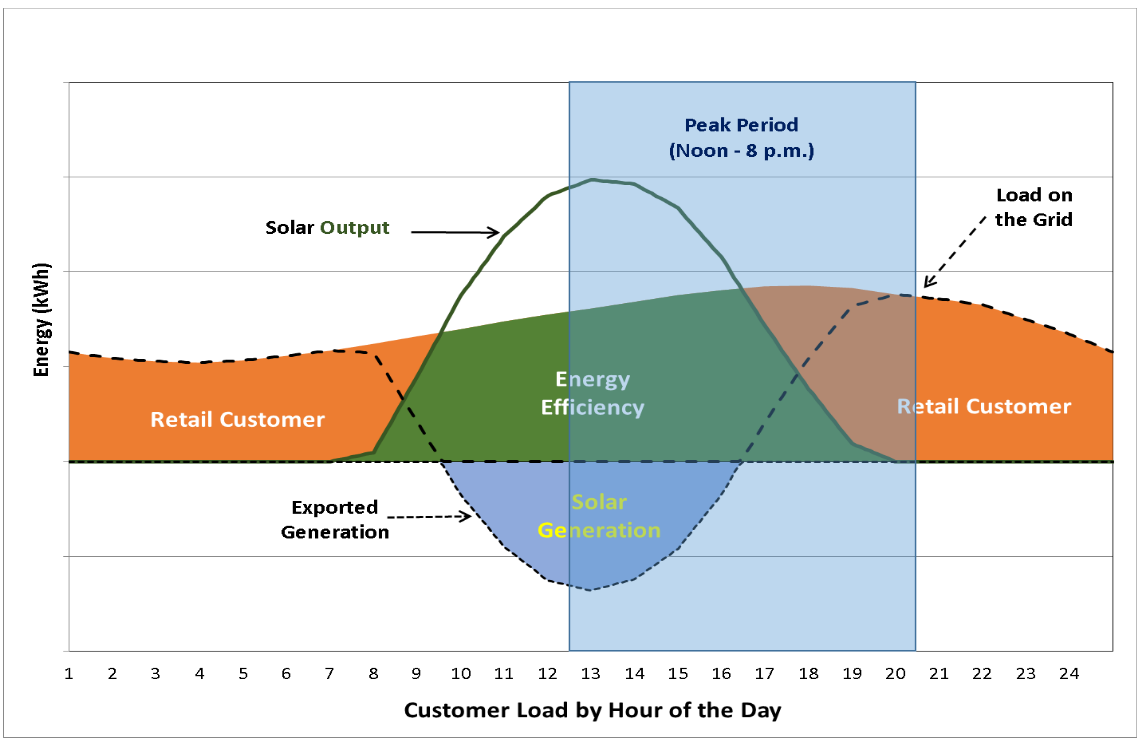
[8] *Ibid.*, at 41-43 and Figure 18.

recognition of this dual role. Appreciating these multiple roles is important, and must be considered in establishing the framework for evaluating the benefits and costs of DG.

Q: Please explain these multiple roles in more detail, using the example of a typical residential NEM customer.

A: To illustrate in detail how net metering works, **Figure 3** shows the three different "states" of a residential net-metered PV system over the course of a day:

Figure 3: *The Three States of Net Metering*



- **The "Retail Customer State."** There is no PV production – for example, at night. At this time, the customer is a regular utility customer, receiving its electricity from the grid. The utility meter rolls forward.
- **The "Energy Efficiency State."** In this state, the sun is up, and there is some PV production but not enough to serve all of the customer's instantaneous load. The customer is supplied with power from the solar PV system as well as with power from the utility. Onsite solar reduces the customer's load on the utility's system in the same fashion as an energy efficiency measure. None of the solar customer's PV production flows out to the utility grid, the meter continues to roll forward, and the customer will pay the utility for his net usage from the grid during these hours.
- **The "Power Export, or Net Metering, State."** In this state, the sun is high overhead, and PV production exceeds the customer's instantaneous use. The on-site solar power serves the customer's entire load, and excess PV generation flows onto the utility's distribution circuit. The utility meter runs backward, producing a net metering credit for the solar customer. In these hours, the solar customer is no longer just a consumer, but is also a producer of power, i.e. a generator. As a matter of physics, the exported power will serve neighboring loads with 100% renewable energy, displacing power that the utility would otherwise generate at a more distant power plant and deliver to that local area over its transmission and distribution system.

This state is the only one in which the customer's generation touches the utility's distribution system or in which a bill credit is produced. In typical PV installations, the percentage of solar output exported to the utility is, on average, about one-third of total PV production; the export percentage can vary significantly above or below this average, depending on the size of the PV system and the hourly profile of the host customer's load. Residential solar customers tend to export a higher percentage of their power output than commercial solar customers.

Q: What do you conclude from this description?

A: Net metering only provides bill credits for power exported to the grid. On-site generation from customer-sited PV that is not exported, i.e., electricity generated in the Energy Efficiency State in Figure 3, is not compensated through net metering. In that case, the customer simply would use his on-site generation to reduce his load, and to the utility the installation of such a DG system would appear no different than if the customer had installed a more efficient air conditioner or simply decided to reduce his power usage in the middle of the day. In fact, if the solar customer did not export power to the grid and 100% of the solar output was consumed on-site, there would be no need for NEM.

Thus, the essence of NEM is the ability of a customer with a solar PV system to "run the meter backwards" when the customer has more generation than the on-site load and is serving as a generation source for the utility system. When the meter runs backward, the DG customer receives credit for his generation exports in the form of a retail rate credit from the utility. In the accounting used to calculate the DG customer's bill, the customer can use these credits to offset usage from the grid when the meter runs forward.

Q: Please discuss the implications for evaluating NEM of the fact that most DG customers are "qualifying facilities" ("QFs") under the Public Utilities Regulatory Policies Act of 1978 ("PURPA").

A: As generators, renewable DG customers typically have legal status as QFs under PURPA. As a result, the serving utility is required under this federal law to do the following:

- to interconnect with a customer's renewable DG system,
- to allow a DG customer to use the output of his system to offset his on-site load, and
- to purchase excess power exported from such systems at a state-regulated price that is based on the utility's avoided costs.[9]

These provisions of federal law exist independent of whether a state has adopted NEM; thus, the adoption of NEM only impacts the accounting credits which the customer-generator receives for power exports to the grid, and the analysis of the economics of NEM should focus only on those exports.

D. Exploding Common Myths about Net Metering

Q: Does the fact that DG customers can be both consumers and producers of electricity mean that they make more use of the utility system than regular utility customers?

[9] The PURPA requirements can be found in 18 CFR §292.303.

A: No. The DG customer either imports power from, or exports power to, the utility's distribution system. When the DG customer imports power from the utility, the customer is using the utility system (including generation, transmission, and distribution), and the meter runs forward. The customer pays the standard tariff rate for that service, including the utility's standard charges for generation and for delivery of the power over the utility's transmission and distribution ("T&D") system.

With exported power, it is not the solar customer who is using the utility system, it is the utility and the solar customer's neighbors, because the title to the exported power transfers to the utility at the solar customer's meter. This is no different than when the utility buys power from any other type of generator – the generator is not responsible for and does not have to pay to deliver the power to the utility's customers. Instead, that delivery service becomes the utility's responsibility when it accepts and takes title to the exported power at the generator's meter. As a generator, the only utility costs for which the generator may be responsible are the incremental costs of interconnecting to the utility system to enable the transfer of generation (and these costs are often paid by the customer-generator).

As a matter of fact, the utility will save money by using the solar customer's exported power to serve the neighbors, because the utility will avoid the costs of the power that it would otherwise have had to generate at a more distant power plant and deliver to that local area over its transmission and distribution system. The essential public policy issue with net metering is whether these "avoided costs" which the utility saves are less than, equal to, or greater than the sum of the net metering credit that the utility provides to the solar customer and the utility's program costs.

What are the key conclusions from this careful analysis of a solar customer's net metering transaction? First, whenever the solar customer uses the utility system (by importing power and rolling the meter forward), the solar customer pays fully for the use of the utility system, at the same rate as any other customer. Second, the solar customer may end up with a small or zero bill from the utility as a result of the accounting offset of the net metering credits which the solar customer earns from power exports (from running the meter backwards). These credits can offset the solar customer's costs of utility service when the customer imports power and the meter runs forward. However, these credits are not the result of the solar customer's use of the utility system; instead, they are the means to account for the exported generation which the solar customer has provided to the utility at the meter. Thus, the solar customer has paid fully for all actual use which the customer has made of the utility system, even though the customer's net bill at the end of the year may be small or even zero. There is the public policy issue of whether the bill credits for exported power at the retail rate are the right credit for those exports – and this case focuses on the methodology for analyzing this issue – but this does not change the fact that the solar customer has paid fully for his or her actual use of the utility system.

Q: Doesn't the utility incur costs to "stand by" to serve a solar customer when the solar customer is exporting power to the grid?

A: No. The costs which the utility incurs to serve a solar customer are no different than those it incurs to stand by to serve a regular utility customer whose usage for periods may be very low – for example, in the middle of the day when the occupants of a house are away at work and school – but who may suddenly impose a load on the system. As a consumer, a solar customer looks like a customer who uses power in the morning, evening, and at night, but who turns everything off in the middle of the day, as illustrated by the dashed "Load on the Grid" line in Figure 3. Such a customer may come home unexpectedly in the middle of the day, turn on lights, a computer, and run an appliance, and produce a sudden spike in usage. But these load fluctuations are something the utility is well-prepared to serve on an aggregate basis, and the costs of such normal "stand by" service are included in the utility's regular rates.

Similarly, a solar customer may suddenly impose a demand on the system if a cloud temporarily covers the sun in the middle of the day. Again, however, this variability is manageable due to the small sizes and geographic diversity of solar DG systems – for example, at the time one PV system is being shaded, another will be coming back into full sunlight.

It is possible that, as solar penetration increases, the aggregate variability of all solar customers' electric output may add to the variability of the power demand that the utility must serve, and impose additional costs for regulation and operating reserves on the system operator. The costs of meeting this added variability is one of the factors considered in solar integration studies, such as the study that Duke Energy Carolinas ("DEC") released earlier this year.[10] This study, as well as others done in other states, shows that such costs are low at the solar DG penetrations expected in South Carolina under the new net metering program.[11]

Q: Doesn't the utility incur costs to store the excess kWh produced by NEM systems, allowing the NEM customer to bank kWh which the customer uses later when the meter is rolling forward?

A: No. Net metering does not involve the storage of electricity, or of energy in any form. This idea is one of the common myths of net metering. Again, the NEM customer is both a consumer and generator of electricity. When the NEM customer is a generator, exporting power in excess of the onsite load, as a matter of physics that generation is immediately consumed by nearby customers. In no way is the power stored for later use. When the solar customer later consumes power from the grid – for example, after the sun sets – the power used is generated and transmitted by the utility at that time. The

---

[10] *Duke Energy Photovoltaic Integration Study: Carolinas Service Areas* (Battelle Northwest National Laboratory, March 2014); hereafter the "Duke Integration Study."

[11] For example, the Duke Integration Study calculates that, with 673 MW of PV capacity on the DEC/DEP systems in 2014, integration costs are about $0.0015 per kWh. See Table 2.5 and Figure 2.51.

fact that NEM credits from exports are used to "offset" the costs of subsequent usage simply represents an accounting for the value of power within the NEM billing arrangement – offsetting a credit with a debit on the customer's account by changing the direction that the meter is recording; it does not represent any actual use of the grid to "store" or "bank" electrons or energy.

E. Key Attributes of a NEM Benefit-Cost Methodology

Q: Please discuss the key attributes of a methodology to assess the benefits and costs of net metered, distributed resources, and show how the legal and policy framework for net metering, including South Carolina's net metering legislation, supports each of these important features.

A: There are four key attributes:

1. **Analyze the benefits and costs from the multiple perspectives of the key stakeholders.** As discussed above, it is important that the Commission assess the benefits and costs of net metering from the perspectives of each of the major stakeholders – the utility system as a whole, participating NEM customers, and other ratepayers – so that the regulator can balance all of these important interests. Examining at all of these perspectives is critical if public policy is to support customer choice and equitable competition between DG providers and the monopoly utility. Section 58-40-20(F)(2) fully supports this attribute, requiring that the benefit/cost methodology should include calculations from all three of these key perspectives.

2. **Analyze the benefits and costs in a long-term, lifecycle time frame.** The benefits and costs of DG should be calculated over a time frame that corresponds to the useful life of a DG system, which, for solar DG, is 20 to 30 years. This treats solar DG on the same basis as other utility resources, both demand- and supply-side. When a utility assesses the merits of adding a new power plant, or a new EE program, the company will look at the costs to build and operate the plant or the program over its useful life, compared to the costs avoided by not operating or building other resource options. The same time frame should be used to assess the benefits and costs of DG. Section 58-40-20(F)(6) contemplates such a long-term analysis, in providing that the "future benefits from net energy metering" can be included in net metering rates to the extent that they provide "quantifiable benefits to the utility system."

3. **Focus on NEM exports.** This testimony has explained how the retail rate credit for power exported to the utility is the essential characteristic of net metering. There would be no need for net metering if no power was exported, and without exports a DG customer appears to the utility grid as simply a retail customer with lower-than-normal consumption. From a legal perspective, PURPA requires the utility to interconnect with the DG customers and to allow the DG customer, at the customer's election, to use its privately-funded generation to serve its own load, on its own private property. It is only when the customer exports power to the utility –

power to which the utility takes title at the meter and uses to serve other customers – that the question arises of how to compensate the DG customer for that power. This is the essential question that net metering answers, and the focus of the net metering analysis should be determining a credit for NEM exports that is fair to all affected parties.

4. **Consider a comprehensive list of benefits and costs.** The location, diversity, and technologies of DG resources will require the analysis of a broader set of benefits and costs than, for example, traditional QF facilities installed under PURPA. Renewable DG projects produce power in many small (less than 1 MW) installations that are widely distributed across the utility system. The power is produced and consumed on the distribution system;[12] indeed, each net-metered DG project is generally associated with a load at least as large as the DG project's output,[13] which will limit the amount of power than is exported to the grid. For example, an important attribute of DG is its ability to serve loads without the use of the transmission system. As DEC notes in describing its utility-owned, behind-the-meter PV DG program: "[p]ower is produced at the site, reducing the need for extensive transmission lines or a complex

---

[12] It is possible that, at high penetrations, DG output to a distribution circuit could exceed the minimum load on the circuit, as has occurred at some locations in Hawaii where, for example, more than 10% of customers on the island of Oahu have installed solar. Such penetrations are not expected to be reached under the limits of the South Carolina net metering program, which is limited to no more than an aggregate capacity of 2% of a utility's average peak demand over the prior five years (Section 58-40-20[B]).

[13] Section 58-40-10(C)(5) states that a net metered system must be "intended primarily to offset part or all of the customer generator's own electrical energy requirements."

infrastructure."[14] Accordingly, an analysis of DG benefits should consider the avoided costs for transmission and distribution losses and capacity.[15] Renewable DG also will avoid the costs associated with environmental compliance at marginal fossil-fueled power plants. On the cost side, the analysis should consider whether solar or wind DG will result in new costs to integrate these variable resources. The next section of this testimony discusses in more detail the specific benefits and costs that should be considered and that can be quantified (as required in Section 58-40-20[F][6]) .

IV. Specific Quantifiable Benefits and Costs

Q: Please list and provide comments on the specific benefits and costs that should be quantified in the net metering methodology.

A: There are several literature reviews or meta-studies which have reviewed the existing NEM/DG benefit/cost studies and have summarized the benefits and costs included in this growing literature:

- A 2013 literature review from the Vermont Commission.[16]
- The Rocky Mountain Institute's ("RMI") 2013 meta-analysis of solar DG benefit and cost studies.[17]

---

[14] See "What are some advantages of solar energy?" http://www.duke-energy.com/north-carolina/renewable-energy/nc-solar-distributed-generation-program-FAQs.asp

[15] Today, it is my understanding that DEC includes avoided capacity related T&D costs as a benefit of its other demand-side programs. See "Stipulation and Agreement" filed August 19, 2013 in North Carolina Utilities Commission Docket No. E-7 Sub 1032, at p. 6.

[16] This literature review, as well as the report and analysis of net metering that the Vermont Commission completed, are available at http://publicservice.vermont.gov/topics/renewable_energy/net_metering .

[17] Rocky Mountain Institute (RMI), "A Review of Solar PV Benefit and Cost Studies" (July 2013), available at http://www.rmi.org/Knowledge-Center%2FLibrary%2F2013-13_eLabDERCostValue.

- The New York State Energy Research and Development Authority ("NYSERDA") recently conducted a literature review of NEM benefit/cost studies, with assistance from E3, in preparation for a NEM study in New York.[18]

Based on this literature, several recent studies have formulated recommended approaches to conducting such analyses, including the specific benefits and costs that should be considered.[19] Finally, cost effectiveness analyses of other types of demand-side programs also draw upon the same categories of benefits and costs, although the fact that DG is generation that can be exported to the grid introduces new categories (such as integration costs).

Based on the above sources and our prior experience with such studies, **Tables 2 and 3** list the specific benefits and costs, respectively, that should be quantified in the Commission's net metering methodology, along with brief comments on the methodology for the quantification of each specific category.

---

[18] See the November 10, 2014 NYSERDA presentation listed at http://ny-sun.ny.gov/About/Stakeholder-Meetings.aspx .

[19] Interstate Renewable Energy Council and Rabago Energy, *A REGULATOR'S GUIDEBOOK: Calculating the Benefits and Costs of Distributed Solar Generation* (October 2013) and Synapse Energy Economics, *Benefit-Cost Analysis for Distributed Energy Resources: A Framework for Accounting for All Relevant Costs and Benefits* (prepared for the Advanced Energy Economy Institute, September 2014).

1 **Table 2:** *Avoided Cost Benefits (for TRC and RIM Tests)*

NEM Benefit Category	Description	Comments on Methodology
Avoided Energy	Change in the variable costs of the marginal system resource, including fuel use and variable O&M, associated with the adoption of DG.	Typically calculated from market energy prices (in deregulated markets), from production cost analyses (for regulated monopoly utilities), or from the energy costs of the proxy marginal resource. Calculation should be granular enough to calculate avoided energy costs of DG resources accurately. These energy costs should be adjusted for the appropriate energy losses (see below).
Avoided Generating Capacity	Change in the fixed costs of building and maintaining new conventional generation resources associated with the adoption of DG.	Forecast of marginal generation capacity costs calculated from market capacity prices (in deregulated markets), from the cost of the least expensive new capacity resource – typically a new combustion turbine peaker (for regulated monopoly utilities), or from the capacity cost of the proxy marginal resource. These capacity costs should be based on public, transparent data, should be adjusted for the appropriate losses (see below), and should reflect the capacity contribution of each type of renewable DG resource.
Avoided Line Losses	Change in electricity losses from the points of generation to the points of delivery associated with the adoption of DG.	Applies to both energy and generating capacity. Should be based on marginal line loss data and DG generation profiles. As a first approximation, marginal line losses are double the system average losses used in cost of service studies and tariffs.
Avoided Ancillary Services	Change in the costs of services like operating reserves, voltage control, and frequency regulation needed for grid stability associated with the adoption of DG.	These costs can be avoided, for example, if such reserves are procured based on loads that DG will reduce. Future DG technologies like "smart inverters" may provide services such as VAR support.
Avoided T&D Capacity	Change in costs associated with expanding/replacing/upgrading T&D capacity associated with the adoption of DG.	Based on marginal capacity costs to expand/replace/upgrade capacity on each IOU's T&D system. Contribution of a DG resource to avoiding transmission or distribution capacity will depend on the contribution of the DG resource to reducing peak loads on the transmission or distribution systems. This analysis will become more location-specific as one moves to lower voltages on the distribution system, where distribution feeders will peak at different times of the day or year.

Avoided Environmental Costs	Change in costs associated with mitigation of SOx, NOx, and PM10 emissions or with waste disposal costs (e.g. coal ash) due to the change in production from each IOU's marginal generating resources as a result of the adoption of DG generation.	Can be included in the Avoided Energy component.
Avoided Carbon Emissions	Change in costs to mitigate CO_2 or equivalent emissions due to the change in production from each IOU's marginal generating resources associated with the adoption of DG.	Based on estimates of the value of carbon emission reductions from utility IRPs or from regulatory agencies with jurisdiction over such emissions. Such reductions can have quantifiable value to ratepayers through avoiding direct emission costs (as in cap & trade markets) or through the costs of resource choices intended to reduce carbon emissions (such as the replacement of coal with natural gas or the construction of carbon-free nuclear or renewable capacity.
Fuel Hedge	Costs to lock in the future price of fuel to match the fixed-price attribute of renewable DG.	Can be approximated through the use of forward natural gas prices to forecast future avoided energy costs, plus the transaction costs of such hedging activities.
Market Price Mitigation	Reduction in energy and capacity wholesale market prices as a result of lower demand resulting from DG adoption.	This benefit of demand-side resources has been quantified in certain U.S. markets (New England and California).
Avoided Renewables	Reduction in above-market generation costs associated with the utility's acquisition of renewable resources, if DG will contribute to meeting the utility's renewable procurement goals.	This benefit will apply to the extent that renewable DG meets a state goal that otherwise would be met with utility-owned or contracted resources. For example, Section 58-39-130(C) requires that any utility's DER program must be designed to acquire capacity in 2021 equal to a minimum of 2% of the utility's peak demand, with one-half of the goal coming from customer-owned or -leased DG.

Table 3: *Costs of DG Programs (for TRC and RIM Tests)*

NEM Cost Category	Description	Comments on Methodology
For TRC Test…		
DG Resource	Capital and O&M costs of the DG resource.	
Integration / Interconnection	Increased costs for regulation and operating reserves to integrate variable renewable DG resources, as well as utility costs to interconnect DG resources.	Integration costs should be those attributable to DG that are incremental to the costs to meet load variability. Interconnection costs should not include such costs if they are paid by the DG customer itself.
Administrative	Utility costs to administer the NEM/DG program.	Should include the incremental costs associated with net metering above those required for regular billing, as well as other administrative costs.
For RIM Test…		
Lost Revenues	Bill credits provided to NEM customers for exported energy.	Will vary depending on the tariff under which the DG customer takes service.
Integration / Interconnection	Same as above	
Administrative	Same as above	

Q: Do you have any general observations on these specific categories of benefits and costs?

A: Yes. First, all of the above categories of benefits and costs are quantifiable, and have been quantified in other NEM or DG benefit/cost studies. As noted above, Section 58-40-20[F][6] requires the Commission to determine that future benefits from NEM must provide "quantifiable benefits to the utility system."

Second, the quantification of these benefits may require data and/or calculations that the utilities may not produce today in the normal course of business. For example, not all utilities calculate marginal line losses or marginal T&D capacity costs, although many do, and there are well-accepted techniques to perform these calculations.

Third, to the extent that studies of relatively complex issues – such as solar or wind integration costs – have yet to be performed, reasonable values for these costs can be derived from such studies performed for other utilities. For example, integration costs at the expected penetration of solar DG could be derived from the Duke Integration Study.

Finally, if there is uncertainty about the magnitude of a specific benefit or cost, the default should not be to assign a zero value to that category. For example, although the costs for mitigating carbon emissions are uncertain, the IRPs of the South Carolina utilities make clear that these costs are not zero for ratepayers, because the utilities are planning today, and spending money today, to reduce their carbon emissions through nuclear construction programs and the replacement of older coal plants with new natural gas-fired generation. For example, the recent IRPs of DEC and Duke Energy Progress recognize the long-term need to reduce CO_2 emissions by maintaining an option to add nuclear generation. This IRP states that "there will be some type of carbon legislation in the future;"[20] prior IRPs have stated that "the Company believes that it needs to plan for a carbon constrained future."[21] The preferred case in Duke's September 2014 IRP is based on CO_2 emissions costs of $17 per ton in

[20] DEC's 2014 IRP, at 30.
[21] DEC's 2012 IRP, Appendix A, p. 110.

2020, escalating to $36 per ton in 2029.[22] Without this assumed carbon cost, the selected plan would be significantly less beneficial for consumers compared to other cases set forth in the IRP that rely more heavily on fossil fuel generation.

The Duke utilities calculate their long-term, avoided energy costs by modeling IRP portfolios which assume the addition of nuclear generation. Because nuclear generation involves lower energy costs than fossil fuel generation, the addition of nuclear generation reduces avoided energy costs compared to a scenario in which fossil fuel resources are added. Thus, inclusion of carbon costs is necessary for a reasonable calculation of avoided energy costs based on the preferred IRP plan.

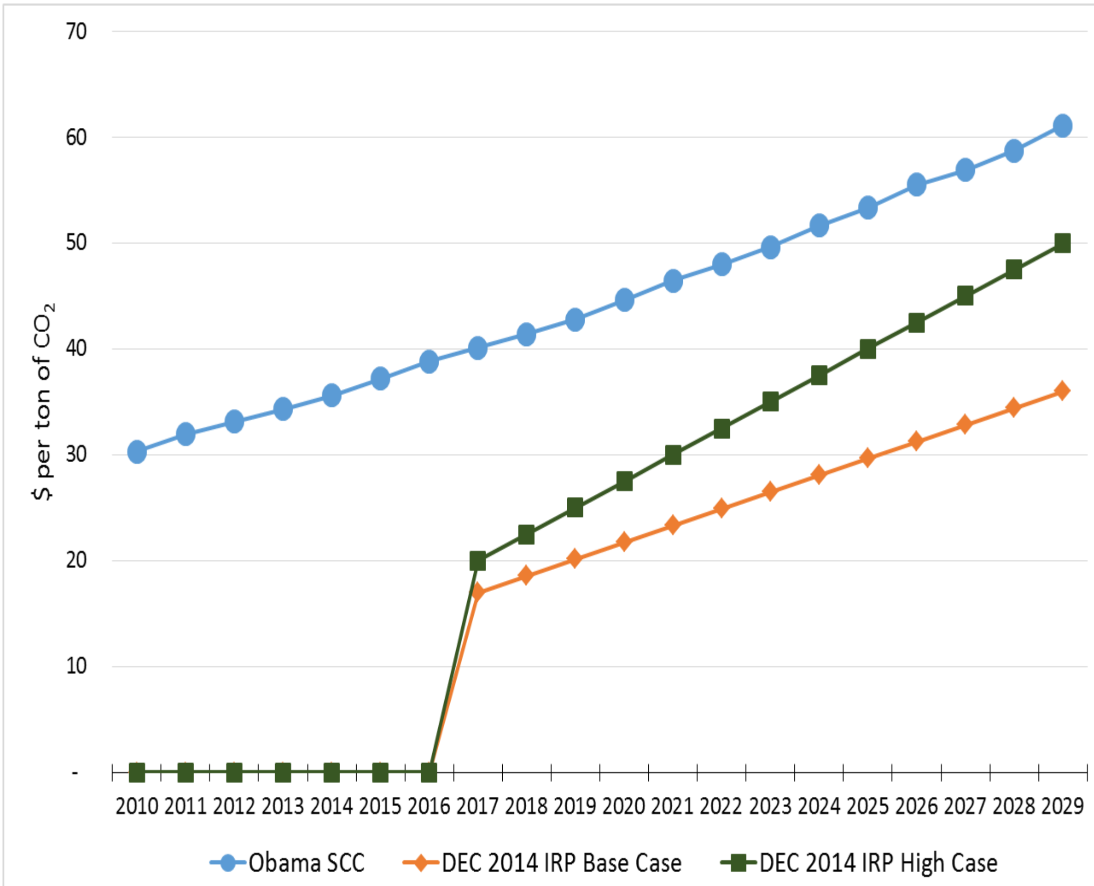
Further, the Environmental Protection Agency's ("EPA") proposed regulations of greenhouse gas (GHG) emissions from power plants under Section 111(d) of the Clean Air Act indicate that the federal government may regulate such emissions based on the administration's social cost of carbon ("SCC") values. The EPA proposal increases the certainty that the utilities will incur significant future costs for reducing carbon emissions.

All of the above considerations underscore the point that a reasonable assumption for future carbon costs is not zero, but should consider a range of possible future mitigation costs. Such a range is shown in **Figure 4**, with

[22] DEC's 2014 IRP, at 50.

carbon costs varying from those that the Duke utilities have assumed in their resource plans up to, in the high case, the federal SCC values.

Figure 4: *Range of Carbon Costs*



V. Application of the Benefit-Cost Methodology to Determine Rates

Q: How should the analysis which you have outlined above be used to determine the rates and charges which will apply to net-metered customers?

A: Any charges or rates imposed through the act should balance the interests of all ratepayers (participants and non-participants), the utilities, and the state of

South Carolina as a whole. Any new charge or rate design applicable to net-metered customers should be tested to ensure that, after it is applied, DG will remain a viable economic proposition for participating ratepayers while not imposing undue upward pressure on the rates of non-participants.

Q: Are there important lessons from other states in terms of how the results of a cost-benefit analysis of NEM may differ among different types and classes of customers?

A: Yes. The impacts of net metering on non-participating ratepayers will vary significantly across customer classes. For example, the costs of NEM are typically lower for commercial and industrial ("C&I") classes than for residential customers, for several reasons. First, C&I rates tend to be lower than residential rates. Second, the solar DG systems of C&I customers tend to export less power to the grid than residential systems, because the diurnal load profile of C&I customers often is a better match for the profile of solar output and because the DG systems installed by C&I customers typically are smaller relative to the size of the on-site load. Finally, rate design has a major impact on the bill savings that NEM customers can realize, and thus on the lost revenues that are the major cost of NEM for non-participating ratepayers. C&I rate designs recover a significant portion of the utility's costs through monthly customer and demand charges that are difficult for solar customers to avoid. Cost studies performed by Southern California Edison ("SCE") have demonstrated that demand charge structures actually overcharge C&I solar customers relative to the costs that they impose on the system, and undervalue the peaking capacity that solar DG provides. As a result, SCE and other California utilities have designed rate options with reduced demand charges but correspondingly higher volumetric time-of-use rates, and make those rate options available to C&I customers who install solar.[23]

Q: Should customer-generators be placed into their own rate classes?

A: No. Customer-generators should not be placed into a separate class without sufficient data to justify distinct treatment. It cannot be assumed that, after installing DG, customers will become significantly different than other customers in the class. For example, data from the residential solar market in Colorado shows that the typical residential customer who installs solar tends to have greater usage than an average customer, with an average monthly pre-solar bill of $126 compared to the average residential bill of $77 per month. After adding solar, the typical solar customer's bill drops to $50 per month.[24] In effect, adding solar changes a larger-than-average customer into a smaller-than-average one, but both are well within the range of sizes typical of the residential class. Last year, the Utah Public Service Commission reached a similar conclusion in rejecting a proposal from Rocky Mountain Power to impose a net metering facilities charge. In Utah, the typical residential

[23] See California PUC Decision No. 13-03-031 (March 21, 2013), at p. 31, discussing Option R rates for Medium and Large Power customers; also, CPUC Decision No. 09-08-028 (August 20, 2009), at p. 22, first implementing Option R rates for SCE Medium and Large Power customers who install solar.

[24] In 2014, the Colorado PUC has held workshops on net metering issues; this information was provided for one of these workshops, based on data from solar customers on the Public Service of Colorado system. See "On-Site Solar Industry Answer to Questions set forth in Attachment A of Commission Decision No. C14-0776-I," filed July 21, 2014 in Colorado PUC Docket No. 14M-0235E, at pp. 8-9.

customer uses 500-600 kWh per month, with net metered customers falling at the low end of this range at 518 kWh per month. The Utah commission concluded that "[t]hese facts undermine PacifiCorp's reasoning that net metered customers shift distribution costs to other residential customers in a fashion that warrants distinct rate treatment."[25]

Q: If the Commission's analysis finds that there is an unreasonable cost shift from customer-generators to non-participating ratepayers, what are the recommended rate design approaches to remedying this problem?

A: There are several. Impacts on non-participants are most likely to be a concern in the residential market, because residential solar systems export a higher percentage of their output and because most of the residential cost of service is recovered through volumetric rates. One solution is to encourage customers to adopt time-of-use rates that align rates more closely to the changes in the utility's costs over the course of a day.[26]

The best rate design solution in the residential market is a monthly minimum bill. The minimum bill is the preferred approach for the following reasons:

- **Addresses the central equity issue.** Minimum bills ensure that all customers make a minimum contribution to the utility infrastructure that serves them. In this way, they address directly the issue of equity between participating and non-participating ratepayers.

[25] Utah PSC, *Report and Order* in Docket No. 13-035-184, at p. 62 (August 29, 2014).
[26] This can include on-peak volumetric rates that recover capacity-related costs. Residential TOU rates should be kept simple and promoted through outreach and education programs, to ensure customer acceptance. Residential demand charges should be avoided due to their complexity, lack of time sensitivity, and unfamiliarity for residential customers.

Minimum bills can have a significant impact to limit the sizing of solar systems, and thus will reduce a utility's future lost revenues.

- **Consistent with cost causation.** The minimum bill can be set to cover the utility's customer-related costs for metering, billing, and customer account services, including any incremental customer-related costs that result from net metering. Thus, minimum bills are consistent with cost causation principles, because they are based on costs which are independent of usage and which the net metering transaction causes the utility to incur.
- **Encourages customer choice.** Because a minimum bill only imposes a floor on the customer's bill and does not apply if usage remains above the minimum bill level, it provides the greatest scope for customers to impact their energy bills by exercising their free-market choice to participate in self-generation.
- **Customer acceptance.** Residential minimum bills have been used for many years by two of the large electric utilities (Pacific Gas & Electric and San Diego Gas & Electric) in California, the state with by far the largest solar market, and have been accepted as fair by net metered solar customers. In contrast, attempts in states such as Arizona, Idaho, and Utah to implement monthly fixed charges on solar customers have not been well-received, and have been perceived as efforts to tax solar production such that it would no

longer be economic.[27] In essence, minimum bills are perceived as a fair balance between allowing customer choice and ensuring that all customers make an equitable contribution to the costs of utility infrastructure.

- **Non-discrimination.** Many states, including South Carolina, have statutory prohibitions against undue discrimination in the design of utility rates.[28] As illustrated by the recent case in Utah cited above, it can be difficult to establish that net metered customers are so different than standard customers that distinct charges for such customers are justified. If fixed charges are raised for all residential customers, there can be adverse bill impacts on all low-usage customers, including low-income ratepayers. A minimum bill is more likely to avoid such problems, as it will apply to a relatively small number of non-net-metered customers.

- **Avoid competitive bypass.** A minimum bill can address impacts on non-participants by providing DG vendors with a strong signal to reduce the sizing of DG systems to keep customers above the minimum bill level, thus reducing the costs of net metering for other ratepayers. This still allows scope for customer choice of DG for usage above the minimum bill level. In contrast, if a fixed charge on

---

[27] See, for example, Idaho PUC, Final Order No. 32846 in Case No. IPC-E-12-27 (July 3, 2013), at pp. 3-5; also Arizona Corporation Commission (ACC), Decision No. 74202 (December 3, 2013), in which the ACC adopted a small fixed charge for new solar DG customers, at a level far below what the utility proposed.

[28] See Section 58-27-840.

residential DG is set too high, as DG and on-site storage technologies continue to develop and as their costs continue to fall, the response of consumers ultimately may be to "cut the cord" completely from utility service, as has happened with landline telephone service in many areas. In my opinion, such a result would be unfortunate, because the utility grid would lose important benefits that DG and on-site storage could provide for all ratepayers, and DG customers would lose the still-important benefits of interconnection to the grid.

ACKNOWLEDGEMENT OF SETTLEMENT

Q. NOTWITHSTANDING YOUR PREVIOUS TESTIMONY, DID TASC ENTER INTO A SETTLEMENT OF THIS MATTER?

A. Yes. I understand that TASC joined the Settlement Agreement that is being filed on December 11, 2014, in the spirit of compromise. TASC supports the Settlement Agreement and asks that the Commission approve it. As discussed in the testimony of TASC Witness Barnes, the Settlement Agreement provides for full retail net metering and includes many other net metering policy design features that will help encourage the development of a solar market in South Carolina.

Q: Does this conclude your testimony?

A: Yes, it does.

Direct Testimony of R. Thomas Beach
The Alliance for Solar Choice
DOCKET NO. 2014-246-E

EXHIBIT RTB-1

Mr. Beach is principal consultant with the consulting firm Crossborder Energy. Crossborder Energy provides economic consulting services and strategic advice on market and regulatory issues concerning the natural gas and electric industries. The firm is based in Berkeley, California, and its practice focuses on the energy markets in California, the western U.S., Canada, and Mexico.

Since 1989, Mr. Beach has participated actively in most of the major energy policy debates in California, including renewable energy development, the restructuring of the state's gas and electric industries, the addition of new natural gas pipeline and storage capacity, and a wide range of issues concerning California's large independent power community. From 1981 through 1989 he served at the California Public Utilities Commission, including five years as an advisor to three CPUC commissioners. While at the CPUC, he was a key advisor on the CPUC's restructuring of the natural gas industry in California, and worked extensively on the state's implementation of PURPA.

AREAS OF EXPERTISE

- *Renewable Energy Issues:* extensive experience assisting clients with issues concerning California's Renewable Portfolio Standard program, including the calculation of the state's Market Price Referent for new renewable generation. He has also worked for the solar industry on the creation of the California Solar Initiative (the Million Solar Roofs), as well as on a wide range of solar issues in other states.

- *Restructuring the Natural Gas and Electric Industries:* consulting and expert testimony on numerous issues involving the restructuring of the electric industry, including the 2000 - 2001 Western energy crisis.

- *Energy Markets:* studies and consultation on the dynamics of natural gas and electric markets, including the impacts of new pipeline capacity on natural gas prices and of electric restructuring on wholesale electric prices.

- *Qualifying Facility Issues:* consulting with QF clients on a broad range of issues involving independent power facilities in the Western U.S. He is one of the leading experts in California on the calculation of avoided cost prices. Other QF issues on which he has worked include complex QF contract restructurings, electric transmission and interconnection issues, property tax matters, standby rates, QF efficiency standards, and natural gas rates for cogenerators. Crossborder Energy's QF clients include the full range of QF technologies, both fossil-fueled and renewable.

- *Pricing Policy in Regulated Industries:* consulting and expert testimony on natural gas pipeline rates and on marginal cost-based rates for natural gas and electric utilities.

EDUCATION

Mr. Beach holds a B.A. in English and physics from Dartmouth College, and an M.E. in mechanical engineering from the University of California at Berkeley.

ACADEMIC HONORS

Graduated from Dartmouth with high honors in physics and honors in English.
Chevron Fellowship, U.C. Berkeley, 1978-79

PROFESSIONAL ACCREDITATION

Registered professional engineer in the state of California.

EXPERT WITNESS TESTIMONY BEFORE THE CPUC

1. Prepared Direct Testimony on Behalf of **Pacific Gas & Electric Company/Pacific Gas Transmission** (I. 88-12-027 — July 15, 1989)

   - *Competitive and environmental benefits of new natural gas pipeline capacity to California.*

2. a. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 10, 1989)
   b. Prepared Rebuttal Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 30, 1989)

   - *Natural gas procurement policy; gas cost forecasting.*

3. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (R. 88-08-018 — December 7, 1989)

   - *Brokering of interstate pipeline capacity.*

4. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029 — November 1, 1990)

   - *Natural gas procurement policy; gas cost forecasting; brokerage fees.*

5. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission and the Canadian Producer Group** (I. 86-06-005 — December 21, 1990)

   - *Firm and interruptible rates for noncore natural gas users*

6. a. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — January 25, 1991)
   b. Prepared Responsive Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — March 29, 1991)

   - *Brokering of interstate pipeline capacity; intrastate transportation policies.*

7. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029/Phase II — April 17, 1991)

   - *Natural gas brokerage and transport fees.*

8. Prepared Direct Testimony on Behalf of **LUZ Partnership Management** (A. 91-01-027 — July 15, 1991)

   - *Natural gas parity rates for cogenerators and solar power plants.*

9. Prepared Joint Testimony of R. Thomas Beach and Dr. Robert B. Weisenmiller on Behalf of the **California Cogeneration Council** (I. 89-07-004 — July 15, 1991)

   - *Avoided cost pricing; use of published natural gas price indices to set avoided cost prices for qualifying facilities.*

10. a. Prepared Direct Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-033 — October 28, 1991)
    b. Prepared Rebuttal Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-0033 — November 26,1991)

    - *Natural gas pipeline rate design; cost/benefit analysis of rolled-in rates.*

11. Prepared Direct Testimony on Behalf of the **Independent Petroleum Association of Canada** (A. 91-04-003 — January 17, 1992)

    - *Natural gas procurement policy; prudence of past gas purchases.*

12. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (I.86-06-005/Phase II — June 18, 1992)
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council** (I. 86-06-005/Phase II — July 2, 1992)

    - *Long-Run Marginal Cost (LRMC) rate design for natural gas utilities.*

13. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 92-10-017 — February 19, 1993)

    - *Performance-based ratemaking for electric utilities.*

14. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-02-014/A. 93-03-053 — May 21, 1993)

    - *Natural gas transportation service for wholesale customers.*

15 a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — June 28, 1993)
   b. Prepared Rebuttal Testimony of Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — July 8, 1993)

    - *Natural gas pipeline rate design issues.*

16. a. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — November 10, 1993)
    b. Prepared Rebuttal Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — January 10, 1994)

    - *Utility overcharges for natural gas service; cogeneration parity issues.*

17. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 93-09-006/A. 93-08-022/A. 93-09-048 — June 17, 1994)

    - *Natural gas rate design for wholesale customers; retail competition issues.*

18. Prepared Direct Testimony of R. Thomas Beach on Behalf of the **SEGS Projects** (A. 94-01-021 — August 5, 1994)

    - *Natural gas rate design issues; rate parity for solar power plants.*

19. Prepared Direct Testimony on Transition Cost Issues on Behalf of **Watson Cogeneration Company** (R. 94-04-031/I. 94-04-032 — December 5, 1994)

    - *Policy issues concerning the calculation, allocation, and recovery of transition costs associated with electric industry restructuring.*

20. Prepared Direct Testimony on Nuclear Cost Recovery Issues on Behalf of the **California Cogeneration Council** (A. 93-12-025/I. 94-02-002 — February 14, 1995)

    - *Recovery of above-market nuclear plant costs under electric restructuring.*

21. Prepared Direct Testimony on Behalf of the **Sacramento Municipal Utility District** (A. 94-11-015 — June 16, 1995)

    - *Natural gas rate design; unbundled mainline transportation rates.*

22. Prepared Direct Testimony on Behalf of **Watson Cogeneration Company** (A. 95-05-049 — September 11, 1995)

    - *Incremental Energy Rates; air quality compliance costs.*

23. a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — January 30, 1996)
    b. Prepared Rebuttal Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — February 28, 1996)

    - *Natural gas market dynamics; gas pipeline rate design.*

24. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 96-03-031 — July 12, 1996)

    - *Natural gas rate design: parity rates for cogenerators.*

25. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 96-10-038 — August 6, 1997)

    - *Impacts of a major utility merger on competition in natural gas and electric markets.*

26. a. Prepared Direct Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — December 18, 1997)
    b. Prepared Rebuttal Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — January 9, 1998)

    - *Natural gas rate design for gas-fired electric generators.*

27. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 97-03-015 — January 16, 1998)

    - *Natural gas service to Baja, California, Mexico.*

28. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 98-10-012/A. 98-10-031/A. 98-07-005 — March 4, 1999).
    b. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — March 15, 1999).
    c. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — June 25, 1999).

    - *Natural gas cost allocation and rate design for gas-fired electric generators.*

29. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — February 11, 2000).
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — March 6, 2000).
    c. Prepared Direct Testimony on Line Loss Issues of behalf of the **California Cogeneration Council** (R. 99-11-022 — April 28, 2000).
    d. Supplemental Direct Testimony in Response to ALJ Cooke's Request on behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — April 28, 2000).
    e. Prepared Rebuttal Testimony on Line Loss Issues on behalf of the **California Cogeneration Council** (R. 99-11-022 — May 8, 2000).

    - *Market-based, avoided cost pricing for the electric output of gas-fired cogeneration facilities in the California market; electric line losses.*

30. a. Direct Testimony on behalf of the **Indicated Electric Generators** in Support of the Comprehensive Gas OII Settlement Agreement for Southern California Gas Company and San Diego Gas & Electric Company (I. 99-07-003 — May 5, 2000).
    b. Rebuttal Testimony in Support of the Comprehensive Settlement Agreement on behalf of the **Indicated Electric Generators** (I. 99-07-003 — May 19, 2000).

    - *Testimony in support of a comprehensive restructuring of natural gas rates and services on the Southern California Gas Company system. Natural gas cost allocation and rate design for gas-fired electric generators.*

31. a. Prepared Direct Testimony on the Cogeneration Gas Allowance on behalf of the **California Cogeneration Council** (A. 00-04-002 — September 1, 2000).
    b. Prepared Direct Testimony on behalf of **Southern Energy California** (A. 00-04-002 — September 1, 2000).

    - *Natural gas cost allocation and rate design for gas-fired electric generators.*

32. a. Prepared Direct Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — September 18, 2000).
    b. Prepared Rebuttal Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — October 6, 2000).

    - *Rate design for a natural gas "peaking service."*

33. a. Prepared Direct Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—April 25, 2001).
    b. Prepared Rebuttal Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—May 15, 2001).

    - *Terms and conditions of natural gas service to electric generators; gas curtailment policies.*

34. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 7, 2001).
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 30, 2001).

    - *Avoided cost pricing for alternative energy producers in California.*

35. a. Prepared Direct Testimony of R. Thomas Beach in Support of the Application of **Wild Goose Storage Inc.** (A. 01-06-029—June 18, 2001).
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Wild Goose Storage** (A. 01-06-029—November 2, 2001)

    - *Consumer benefits from expanded natural gas storage capacity in California.*

36. Prepared Direct Testimony of R. Thomas Beach on behalf of the **County of San Bernardino** (I. 01-06-047—December 14, 2001)

    - *Reasonableness review of a natural gas utility's procurement practices and storage operations.*

37. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)
    b. Prepared Supplemental Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)

    - *Electric procurement policies for California's electric utilities in the aftermath of the California energy crisis.*

38. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association** (R. 02-01-011—June 6, 2002)

- *"Exit fees" for direct access customers in California.*

39. Prepared Direct Testimony of R. Thomas Beach on behalf of the **County of San Bernardino** (A. 02-02-012 — August 5, 2002)

- *General rate case issues for a natural gas utility; reasonableness review of a natural gas utility's procurement practices.*

40. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association** (A. 98-07-003 — February 7, 2003)

- *Recovery of past utility procurement costs from direct access customers.*

41. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — February 28, 2003)
b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — March 24, 2003)

- *Rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord II).*

42. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — March 21, 2003)
b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — April 4, 2003)

- *Cost allocation of above-market interstate pipeline costs for the California natural gas utilities.*

43. Prepared Direct Testimony of R. Thomas Beach and Nancy Rader on behalf of the **California Wind Energy Association** (R. 01-10-024 — April 1, 2003)

- *Design and implementation of a Renewable Portfolio Standard in California.*

44. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 23, 2003)
    b. Prepared Supplemental Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 29, 2003)

    - *Power procurement policies for electric utilities in California.*

45. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Indicated Commercial Parties** (02-05-004 — August 29, 2003)

    - *Electric revenue allocation and rate design for commercial customers in southern California.*

46. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 16, 2004)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 26, 2004)

    - *Policy and rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord III).*

47. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 04-04-003 — August 6, 2004)

    - *Policy and contract issues concerning cogeneration QFs in California.*

48. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 11, 2005)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 28, 2005)

    - *Natural gas cost allocation and rate design for large transportation customers in northern California.*

49. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — March 7, 2005)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — April 26, 2005)

    - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

50. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Solar Energy Industries Association** (R. 04-03-017 — April 28, 2005)

- *Cost-effectiveness of the Million Solar Roofs Program.*

51. Prepared Direct Testimony of R. Thomas Beach on behalf of **Watson Cogeneration Company, the Indicated Producers, and the California Manufacturing and Technology Association** (A. 04-12-004 — July 29, 2005)

- *Natural gas rate design policy; integration of gas utility systems.*

52. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — August 31, 2005)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — October 28, 2005)

- *Avoided cost rates and contracting policies for QFs in California*

53. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — January 20, 2006)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — February 24, 2006)

- *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in southern California.*

54. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Producers** (R. 04-08-018 – January 30, 2006)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Producers** (R. 04-08-018 – February 21, 2006)

- *Transportation and balancing issues concerning California gas production.*

55. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 06-03-005 — October 27, 2006)

- *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

56. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 05-12-030 — March 29, 2006)

- *Review and approval of a new contract with a gas-fired cogeneration project.*

57. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 14, 2006)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 31, 2006)

    - *Restructuring of the natural gas system in southern California to include firm capacity rights; unbundling of natural gas services; risk/reward issues for natural gas utilities.*

58. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 06-02-013 — March 2, 2007)

    - *Utility procurement policies concerning gas-fired cogeneration facilities.*

59. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 07-01-047 — August 10, 2007)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 07-01-047 — September 24, 2007)

    - *Electric rate design issues that impact customers installing solar photovoltaic systems.*

60. a. Prepared Direct Testimony of R,. Thomas Beach on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — May 15, 2008)
    b. Prepared Rebuttal Testimony of R,. Thomas Beach on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — June 13, 2008)

    - *Utility subscription to new natural gas pipeline capacity serving California.*

61. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-015 — September 12, 2008)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-015 — October 3, 2008)

    - *Issues concerning the design of a utility-sponsored program to install 500 MW of utility- and independently-owned solar photovoltaic systems.*

62. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-002 — October 31, 2008)

- *Electric rate design issues that impact customers installing solar photovoltaic systems*.

63. a. Phase II Direct Testimony of R. Thomas Beach on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — December 23, 2008)
    b. Phase II Rebuttal Testimony of R. Thomas Beach on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — January 27, 2009)

- *Natural gas cost allocation and rate design issues for large customers.*

64. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 09-05-026 — November 4, 2009)

- *Natural gas cost allocation and rate design issues for large customers.*

65. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 5, 2010)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 26, 2010)

- *Revisions to a program of firm backbone capacity rights on natural gas pipelines.*

66. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 10-03-014 — October 6, 2010)

- *Electric rate design issues that impact customers installing solar photovoltaic systems*.

67. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Indicated Settling Parties** (A. 09-09-013 — October 11, 2010)

- *Testimony on proposed modifications to a broad-based settlement of rate-related issues on the Pacific Gas & Electric natural gas pipeline system.*

68. a. Supplemental Prepared Direct Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 6, 2010)
    b. Supplemental Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 13, 2010)
    c. Supplemental Prepared Reply Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 20, 2010)

    - *Local reliability benefits of a new natural gas storage facility.*

69. Prepared Direct Testimony of R. Thomas Beach on behalf of **The Vote Solar Initiative** (A. 10-11-015—June 1, 2011)

    - *Distributed generation policies; utility distribution planning.*

70. Prepared Reply Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 10-03-014—August 5, 2011)

    - *Electric rate design for commercial & industrial solar customers.*

71. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 11-06-007—February 6, 2012)

    - *Electric rate design for solar customers; marginal costs.*

72. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Northern California Indicated Producers** (R.11-02-019—January 31, 2012)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Northern California Indicated Producers** (R. 11-02-019—February 28, 2012)

    - *Natural gas pipeline safety policies and costs*

73. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 11-10-002—June 12, 2012)

    - *Electric rate design for solar customers; marginal costs.*

74. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002—June 19, 2012)

    - *Natural gas pipeline safety policies and costs*

75. a. Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 12-03-014—June 25, 2012)
b. Reply Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 12-03-014—July 23, 2012)

- *Ability of combined heat and power resources to serve local reliability needs in southern California.*

76. a. Prepared Testimony of R. Thomas Beach on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002, Phase 2—November 16, 2012)
b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002, Phase 2—December 14, 2012)

- *Allocation and recovery of natural gas pipeline safety costs.*

77. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 12-12-002—May 10, 2013)

- *Electric rate design for commercial & industrial solar customers.*

EXPERT WITNESS TESTIMONY BEFORE THE COLORADO PUBLIC UTILITIES COMMISSION

1. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the Colorado Solar Energy Industries Association and the Solar Alliance, (Docket No. 09AL-299E – October 2, 2009).

- *Electric rate design policies to encourage the use of distributed solar generation.*

2. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the Vote Solar Initiative and the Interstate Renewable Energy Council, (Docket No. 11A-418E – September 21, 2011).

- *Development of a community solar program for Xcel Energy.*

EXPERT WITNESS TESTIMONY BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

1. Direct Testimony of R. Thomas Beach on behalf of the **Idaho Conservation League** (Case No. IPC-E-12-27—May 10, 2013)

    - *Costs and benefits of net energy metering in Idaho.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF NEVADA

1. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 97-2001—May 28, 1997)

    - *Avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

2. Pre-filed Direct Testimony on Behalf of **Nevada Sun-Peak Limited Partnership** (Docket No. 97-6008—September 5, 1997)

3. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 98-2002 — June 18, 1998)

    - *Market-based, avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

EXPERT WITNESS TESTIMONY BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

1. Direct Testimony of R. Thomas Beach on Behalf of the **Interstate Renewable Energy Council** (Case No. 10-00086-UT—February 28, 2011)

    - *Testimony on proposed standby rates for new distributed generation projects; cost-effectiveness of DG in New Mexico.*

2. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the **New Mexico Independent Power Producers** (Case No. 11-00265-UT, October 3, 2011)

    - *Cost cap for the Renewable Portfolio Standard program in New Mexico*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF OREGON

1. a. Direct Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — August 3, 2004)
   b. Surrebuttal Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — October 14, 2004)

2. a. Direct Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — February 27, 2006)
   b. Rebuttal Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — April 7, 2006)

   - *Policies to promote the development of cogeneration and other qualifying facilities in Oregon.*

EXPERT WITNESS TESTIMONY BEFORE THE VIRGINIA CORPORATION COMMISSION

1. Direct Testimony and Exhibits of R. Thomas Beach on Behalf of the Maryland – District of Columbia – Virginia Solar Energy Industries Association, (Case No. PUE-2011-00088, October 11, 2011)

   - *Standby rates for net-metered solar customers, and the cost-effectiveness of net energy metering.*

EXPERT WITNESS TESTIMONY BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

1. Direct and Rebuttal Testimony of R. Thomas Beach on Behalf of Geronimo Energy, LLC. (In the Matter of the Petition of Northern States Power Company to Initiate a Competitive Resource Acquisition Process [OAH Docket No. 8-2500-30760, MPUC Docket No. E002/CN-12-1240, September 27 and October 18, 2013])

   - *Testimony in support of a competitive bid from a distributed solar project in an all-source solicitation for generating capacity.*

EXPERT WITNESS TESTIMONY BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

1. Direct, Response, and Rebuttal Testimony of R. Thomas Beach on Behalf of the North Carolina Sustainable Energy Association. (In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2014; Docket E-100 Sub 140; April 25, May 30, and June 20, 2014)

   - *Testimony on avoided cost issues related to solar and renewable qualifying facilities in North Carolina.*

LITIGATION EXPERIENCE

Mr. Beach has been retained as an expert in a variety of civil litigation matters. His work has included the preparation of reports on the following topics:

- The calculation of damages in disputes over the pricing terms of natural gas sales contracts (2 separate cases).
- The valuation of a contract for the purchase of power produced from wind generators.
- The compliance of cogeneration facilities with the policies and regulations applicable to Qualifying Facilities (QFs) under PURPA in California.
- Audit reports on the obligations of buyers and sellers under direct access electric contracts in the California market (2 separate cases).
- The valuation of interstate pipeline capacity contracts (3 separate cases).

In several of these matters, Mr. Beach was deposed by opposing counsel. Mr. Beach has also testified at trial in the bankruptcy of a major U.S. energy company, and has been retained as a consultant in anti-trust litigation concerning the California natural gas market in the period prior to and during the 2000-2001 California energy crisis.